

# Drop-In Control House for a Large 230 kV Transmission Substation: A Case Study in Implementation

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# **DROP-IN CONTROL HOUSE FOR A LARGE 230 KV TRANSMISSION SUBSTATION: A CASE STUDY IN IMPLEMENTATION**

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## **INTRODUCTION**

In 1998, a large Southern Utility began developing an automation strategy for upgrading transmission class substations. The primary driver for the substation upgrade work was reliability concerns associated with the aging electrical grid infrastructure. The objectives for the new automation design platform were to improve system reliability, reduce maintenance costs, enhance operability, develop design standards, and improve and increase substation data collection to assist in maintenance and engineering analysis.

Like a majority of electric utility companies, much of the utility's transmission substation protective and control equipment is over 30–40 years old and is in dire need of upgrade and replacement. Like most utilities, this Utility historically used separate equipment and components for performing the protective relaying, control, metering, and alarming substation functionality. This legacy equipment consists of many separate components, including protective relays, discrete components (including switches, lockout, and panel lights), remote terminal units (RTUs), sequence-of-events (SOE) recorders, analog fault recorders (AFR), annunciators, mimic bus control panels, and meters.

## **UTILITY IMPLEMENTS AUTOMATED SOLUTION**

This Utility implemented its first fully integrated substation solution in the fall of 1999 at Albemarle switching station. In 2000, after the success of the Albemarle project, two more substation automation projects were implemented utilizing the integrated solution at an existing substation, Acrerock Tie, and a new transmission substation, Walker Tie.

At both Albemarle and Acrerock, the existing control house was used, while at Walker Tie, a new control house was built on site. After the successful completion of three integrated substation projects, the Utility's engineering team looked at alternative solutions for lowering costs, limiting potential human errors, and reducing equipment outage and field commissioning time. After reviewing several options, it was determined that the best solution for performing the same integrated upgrade at a transmission class substation was to have the system delivered to the substation as a complete, pre-engineered and pre-assembled "drop-in" control house. The relaying and control equipment could be pre-tested as a system, either at the factory or on-site, before the commissioning phase of the project began. The pre-wired and pre-tested building could arrive at the site ready for installation and field wiring to the house switchyard termination cabinets. Through 2002, while outsourcing the control engineering and construction, the Utility implemented automation upgrades utilizing the drop-in control house integrated solution at 12 transmission class substations and realized significant construction and implementation cost savings, reduced field commissioning time, and reduced human errors.

## JUSTIFICATION FOR AUTOMATION SOLUTION AT LARGER 230 kV TRANSMISSION SUBSTATIONS

The previous 15 transmission class substations that were selected for the integrated upgrade between 1999 and 2002 were smaller 100 kV/44 kV substations and were considered less critical to the system electrical grid. The Utility's engineers realized that it was time to consider implementing the drop-in control house integration solution at some of the more critical larger 230 kV transmission substations.

As was done when the decision was made to upgrade the smaller scale transmission substations in 1998, the engineers studied several options for performing station upgrades at larger transmission substations. It was determined that there were basically two options. The first option was to replace individual relay terminals within the existing substation control house as required based on age, obsolescence, and asset importance. The second option was to use a similar approach to the one taken for the smaller transmission station upgrades by implementing a drop-in control house fully automated solution.

Some drawbacks realized for the individual terminal replacement option are the following:

1. Individual terminal replacement addresses only issues relating to the specific terminal panel components and does not address obsolescence issues relating to associated control, monitoring, and metering equipment. Separate replacement programs, including additional and separate funding, would have to be established to address the replacement of the following equipment:
  - a. Supervisory Control and Data Acquisition (SCADA) Equipment—Replacement of obsolete substation RTUs, including current, voltage, and watt/var transducers. One RTU replacement at a typical transmission substation could cost up to \$110,000.
  - b. Cabling—Substation metering and control cable has a limited lifespan and at some point will need to be replaced. A separate program for replacing only the cables at an existing station while keeping the existing control house intact and using the existing tray system intact would be a costly and near impossible endeavor.
  - c. Programmable Logic Controller (PLC)—PLCs utilized for capacitor controllers, swap over schemes, carrier playback testing, station annunciators that play an integral part in system voltage control and stability, and station alarming have a limited lifespan and eventually need to be replaced.
  - d. Sequence-of-Events (SOE) Recorder —Replacement of obsolete SOE Recorders with a new recorder including the replacement of the cabling to each terminal and associated relays at a typical transmission substation could cost up to \$85,000.
  - e. Communications Systems—Replacement of existing substation communications equipment including protective relay communications equipment and systems, remote control communications systems, data transfer systems, and emergency alarming dial-out systems would become costly if performed under a separate program.
  - f. Analog Fault Recorders (AFRs)—Replacement of obsolete AFRs with associated components and cabling to each terminal could cost up to \$95,000.
  - g. Mimic Bus Panels and Metering Panels—Replacement or upgrade of these panels in a separate program would be complex due to the fact that field wiring is typically landed at

these panels first; hence, if eight panels were reduced to three and the cabling was reused, the majority of the cables would have to be spliced to be re-terminated.

- h. Control House—Existing control houses would have to be repaired and updated, including the roofs, ceilings, walls, and doors. Some of the control houses in the Utility's substations are over 50 years old and do not have insulation. The costs of the repairs and maintenance of these facilities would be very high.
  - i. Asbestos Removal—Several of the transmission substations at this Utility contain asbestos panels, flooring, ceilings, and insulation. As per EPA regulation, the asbestos panels cannot be disturbed and any modifications to those panels are not permitted.
- 2. Individual terminal replacements would require maintaining existing substation architecture and schemes, limiting automation upgrades that use newer technology, and preventing future functionality and data collection enhancements.
- 3. The upgrading of an entire substation by replacing individual terminals in the existing control house would require a more intensive detailed coordination plan by the implementation team, longer outages, a longer overall cutover schedule, and would significantly increase the project costs.
- 4. Performing a complete checkout of station protection and control schemes during the implementation phase would be very difficult. Replacing individual terminals one by one would significantly increase the potential for human errors during the field commissioning process.

The second option for performing a station upgrade on the larger transmission substations was to implement the drop-in control house automated solution as was implemented with the smaller, less critical transmission substations. The integration of the substation controls, monitoring, and data acquisition functionality would be achieved by utilizing the capabilities of the microprocessor protective relays and communications processors. The many benefits associated with the integrated solution using the pre-engineered, pre-designed, pre-assembled, pre-wired, and pre-tested building (as were achieved on the smaller transmission substation implementations) clearly made it the best solution.

The significant benefits that have been realized by the integrated solution are:

- 1. Reduction in capital equipment costs as well as engineering and design costs by significantly reducing and eliminating the numerous station components.
- 2. Elimination of periodic maintenance cycles for the electrical terminals by applying highly reliable microprocessor relays with self-testing and self-alarming diagnostics.
- 3. Reduction in maintenance of the power system apparatus, including circuit breakers and transformers through the collection of breaker wear data and transformer loss-of-life data from the IEDs. Periodic maintenance of power system assets is being replaced with predictive maintenance because better information indicates when and what type of maintenance needs to be performed.
- 4. Reduction in operational costs by standardizing on single vendors and simplifying the station operator interface via the human-machine interface (HMI) or via the front of the relays. Operators can more efficiently operate the station during emergency situations.

5. Reduction in potential human errors by providing enhanced station operability and functionality.
6. Improvements in safety-related issues due to enhanced protective features in the microprocessor relays.
7. Increase in productivity by the station operators due to the automatic collection and storage of substation data, such as fault location data, SOE data, and more detailed alarm data. The easy accessibility of these data reduces time required to analyze and rectify system outages and provides users with an increased understanding of power system asset status and operation.
8. Reduction in installation costs due to simplified field interconnections achieved by providing a field termination box in the control house. This allows a simple above-ground cable tray system to be installed that brings all apparatus cabling into the control house cabinet for terminating.
9. A more thorough checkout of the entire station protection and control schemes can be performed and a significant reduction in potential human errors is realized during the implementation phase because the control house is pre-engineered, pre-designed, pre-assembled, pre-wired, and pre-tested.

## **SELECTION CRITERIA FOR AUTOMATION UPGRADE**

Each year this Utility allocates a percentage of capital dollars for funding complete station upgrades implementing the drop-in control house automated solution. The engineers have established a selection criteria for determining which transmission stations have the most functional problems from a relay and operational perspective. The yearly capital dollars available define the quantity of stations to be upgraded. Stations are then selected based on their scoring against the established criteria.

The six selection criteria established for selecting the targeted substations are as follows:

1. Asset Importance—defines how critical the substation is to the system regarding system stability, voltage support, load flow, generation connectivity, and black startup.
2. Relay Obsolescence—the percentage of protective relays that would be considered obsolete or poor performers and that would be included in an individual relay terminal replacement program.
3. Environmental Issues—identifies the quantity and the severity of environmental issues existing in the substation control house. The primary concerns are with asbestos panels, flooring, and ceilings that require stringent EPA guidelines and procedures for removal and disposal.
4. Control House—determines the general condition of the existing control house facilities including roof, HVAC, lighting, ceilings, walls, restroom, etc.
5. Control Cable—determines the condition of control, current, and voltage cables.
6. DC System—determines the general condition of the battery bank. Some of their substations have dual 250/125 Vdc battery systems and it is more cost effective to replace the dual system during a complete station upgrade.

## TIGER TIE SUBSTATION

In the fall of 2002, the Utility's engineers reviewed potential transmission substation automation upgrades for 2003 and determined that Tiger Tie substation located in Greer, SC met all selection criteria and was the best choice for performing a complete station upgrade utilizing the drop-in control house automated solution.



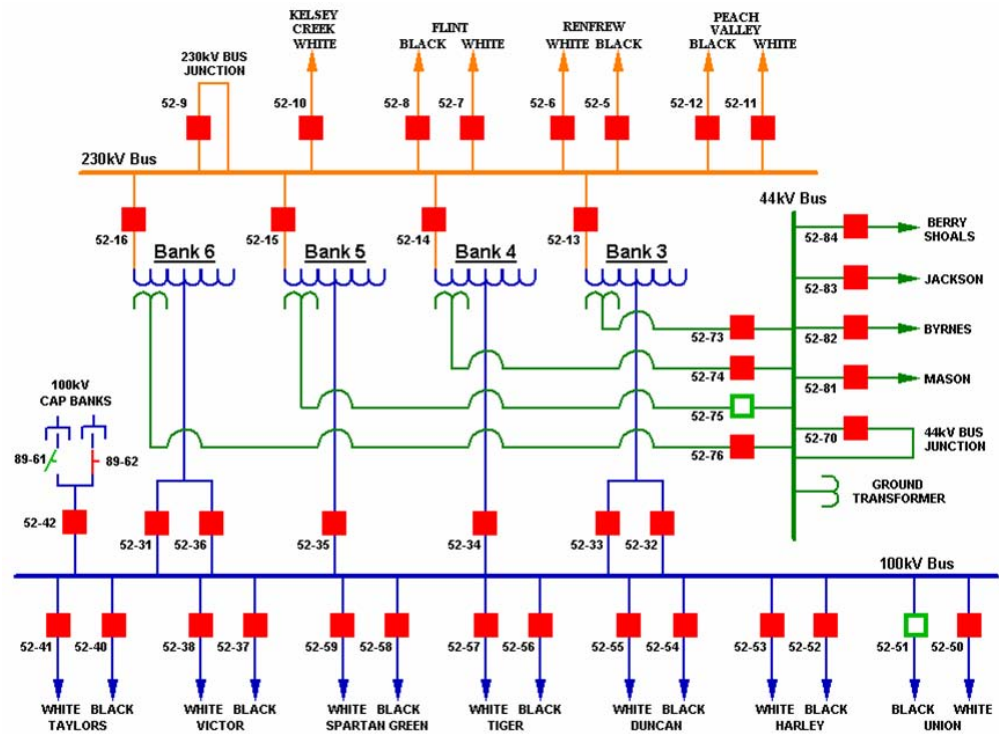
**Figure 1** Tiger Tie Substation

Tiger Tie substation is a major transmission substation in the Utility's electric grid that delivers power to a large area of western South Carolina, including parts of Greenville, SC and Spartanburg, SC. Tiger Tie provides critical voltage support and system stability for this area of their electrical grid. The station's several key industrial facilities include a BMW automobile plant, a Michelin Tire plant, and several small textile mills and industrial plants. The Tiger Tie substation was built in the 1930s and, like most stations built at that time in the Carolinas, was built to provide voltage stability to many of the textile mills in the area. Originally, there was a small power plant built next to the station that was decommissioned in the 1960s. The original station control house built in the 1930s was a larger brick building that housed the relay and control equipment as well as, at the time, the plant switchgear. When additional circuits were added in the 1970s due to the lack of space in the original control house, a second metal frame building was built to accommodate future station additions. The older brick control house had various maintenance, repair, and environmental issues. Relay panels, flooring, and ceiling contained high levels of asbestos. Due to the obsolescence of the existing relaying and control equipment, it was apparent that a majority of the equipment needed to be replaced. Many of the cables were 45–50 years old and needed replacing. Tiger also had a dual battery system that needed replacing. It was clear that Tiger was an excellent choice for a station upgrade.

The station consists of the following equipment and circuits:

1. Seven (7) 230 kV tie lines
2. One (1) 230/100/44 kV 400 MVA autobank, one (1) 230/100/44 kV 200 MVA autobank, and two (2) 230/100/44 kV 150 MVA autobanks
3. Twelve (12) 100 kV tie lines

4. Two (2) 100 kV radial lines
5. Two (1) 100 kV 80 MVAR capacitor banks
6. Four (4) 44 kV lines



**Figure 2** Tiger Tie One-Line Diagram



**Figure 3** Old Control Houses at Tiger Tie Substation

## Existing Station Equipment

The existing protective relaying and control at Tiger Tie included a total of approximately 60 protective relaying and control panels with several thousand discrete components, including protective relays, monitoring and control devices (AFRs, RTUs, SOE recorders, PLCs), auxiliary relays, switches, and indicating lights. As stated previously, Tiger Tie had two control houses (shown in Figure 3), one brick building approximately 70' x 70' and another metal building approximately 50' x 20'. The original Tiger Tie substation design utilized the traditional relay and control design approach with the following equipment:

1. The 230 kV, 100 kV, and 44 kV transmission line protection design required a primary distance relay panel and a separate backup relay panel with many electromechanical relays, discrete relays, and switches.
2. The breaker failure relaying design for the 230 kV, 100 kV, and 44 kV circuits included discrete relays and timers located on separate panels.
3. The mimic bus style operator control panels for station control and metering required several panels.
4. Separate metering panels provided the station watt/var metering.
5. Station SCADA control utilized several RTU panels.
6. Separate SOE recorder panels and AFR panels provided the station events recording and system disturbance data.
7. Autobank emulsifier system panels provided the control and alarming for the transformer emulsifier systems.
8. Underfrequency load shedding protective relaying was located on separate panels.
9. PLC-based capacitor controllers provided protection and control of the station capacitor bank that was located in the switchyard.
10. Local station alarming required a separate annunciator panel.





**Figure 4** Tiger Tie—Existing Operator Interface Mimic Bus Control Panel (Asbestos Panels)



**Figure 5** Tiger Tie—Existing 100/44 kV Panels

## **TIGER TIE DROP-IN CONTROL HOUSE SOLUTION**

The new automated drop-in control house engineering design utilized for the relay and control upgrade at Tiger Tie provides more robust relaying, metering, and control functionality and significantly reduces the substation components. The quantity of panels was reduced to 26 (less than half the original quantity) with approximately 95 microprocessor relays and communications processors. The new design also reduced the number of unique manufactured components, electromechanical and auxiliary relays, meters, RTUs, SOEs, AFRs, and PLCs from over 100 to less than 15. The new “drop-in” control house was significantly reduced in size to a 40’ x 16’ pre-assembled, pre-wired metal building and a separate 12’ x 12’ battery house that was set on pre-poured concrete piers.



**Figure 6** New Control House and Battery House

The new Tiger Tie protective relaying and control design consisted of the following panels and components:

1. Communications panels
  - a. HMI computer for local station operator interface.
  - b. SEL-2032 Communications Processors for performing data concentration and SCADA functionality.
  - c. Telecommunications equipment including an OC3 sonic ring gateway, fiber distribution panel, and a 48 Vdc system for providing interface to the communications network.
  - d. UPS inverter for providing uninterruptible power to all integration equipment.
  - e. GPS satellite clock receiver for providing IRIG-B time synchronized signal to all station IEDs.
  - f. IMUX terminal multiplexer for providing the communications links to their network for the 230 kV pilot protection, SCADA, and phone circuits.
  - g. Digital modem for DNP3 link for SCADA monitoring and control.
  - h. Digital modem connected to a router and Ethernet hub for the highly secured T1 network connection to the station computer for local Intranet access and for providing fast reliable connection for passing 1,750 PI data points back to the General Office. Also provides secure network connection for laptop computers.
  - i. Telephone line port switcher for utilizing a single analog line for dialup access to six analog modems.
    - i) Backup station alarming.
    - ii) HMI backup remote control via a secured NetOp connection.

- iii) Engineer access to the microprocessor relays and for retrieving fault data.
  - iv) Digital modem access for remote setting and diagnostics.
  - v) Ethernet router access for remote setting and diagnostics.
  - vi) Multiplexer access for remote setting and diagnostics.
- j. Weather station for monitoring control house and outdoor weather conditions, including temperature, humidity, and pressure.
- 2. One (1) 230 kV Bus Differential Panel—GE SBD relays for red and yellow bus differential protection and SEL-351/SEL-2505 Relays for the 230 kV bus junction overcurrent protection, reclosing control, and breaker failure.
- 3. Four (4) 230/100/44 kV Autobank Panels—SEL-387 Relays for the primary and backup bank differential protection, transformer emulsifier control system, SEL-351/SEL-2505 Relays for the overcurrent and breaker failure protection, and SEL-701-1 Relay for transformer alarming and cooling control.
- 4. Four (4) 230 kV Tie Line Distance Protection Panels—pilot protection, line distance, overcurrent protection, reclosing control, and breaker failure. SEL-421 Relay for the primary and SEL-311B/SEL-2505 Relays for the backup distance relaying; two line terminals per panel.
- 5. Six (6) 100 kV Tie Line Distance Protection Panels—SEL-311C Relay for the primary line distance protection and underfrequency load shedding and SEL-311B/SEL-2505 Relays for the backup distance, overcurrent, and breaker failure protection and reclosing control; two line terminals per panel.
- 6. One (1) 100 kV Radial Line Protection Panel—SEL-351/SEL-2505 Relays for primary line overcurrent and underfrequency load shedding, reclosing control, and breaker failure and SEL-551 Relay for backup overcurrent protection; two line terminals on each panel.
- 7. One (1) 100 kV Bus Differential Panel—GE SBD relays for red and yellow bus differential protection.
- 8. One (1) 100 kV Capacitor Bank Panel—SEL-351/SEL-2505 Relays for the capacitor overcurrent protection, automatic capacitor control, and breaker failure and SEL-551 Relay for the neutral unbalance protection.
- 9. Two (2) 44 kV Radial Line Protection Panel—SEL-351/SEL-2505 Relays for primary line overcurrent and underfrequency load shedding, reclosing control, and breaker failure and SEL-551 Relay for backup overcurrent protection; two line terminals per panel.
- 10. One (1) 44 kV Bus Differential Panel—SEL-351 Relays for the 44 kV red and 44 kV yellow bus overcurrent differential protection, SEL-351/SEL-2505 Relays for the 44 kV bus junction overcurrent protection, reclosing control and breaker failure, and SEL-351 Relay for the 44 kV ground bank overcurrent protection.



**Figure 7** New 230 kV/Autobank Protection Panels



**Figure 8** New 100 kV/44 kV Protection Panels





**Figure 9** HMI and Communications Panel

## **TIGER TIE AUTOMATION DESIGN HIGHLIGHTS AND IMPROVEMENTS**

The primary benefits and achievements of the drop-in control house solution are the integration of the substation control, monitoring, and data acquisition functionality into the protective relays and communications processors. The communications processors perform the data concentration and SCADA functionality and provide the link between the relays and the substation HMI computer as well as the link between the relays and the Transmission Control Center (TCC). The TCC is responsible for monitoring and operating the transmission system.

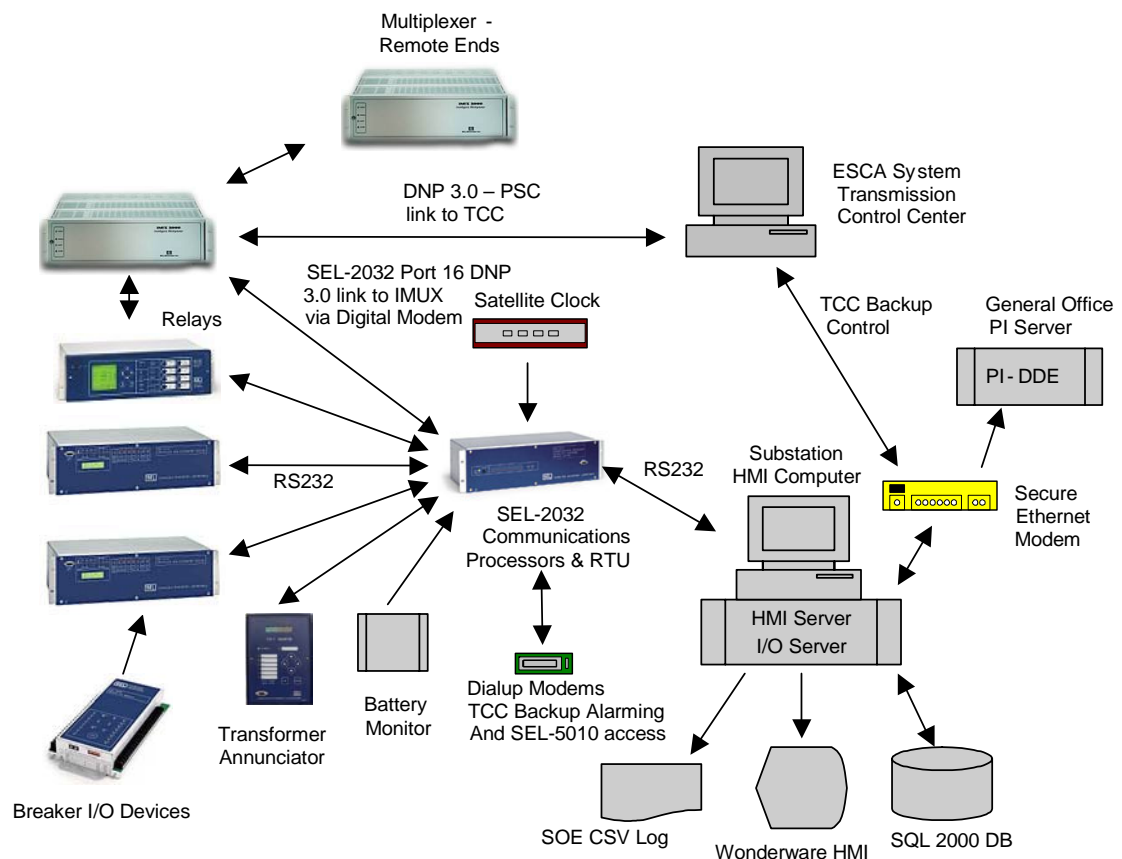
The integrated solution implemented at Tiger Tie provided the following significant improvements and enhancements in the control, metering, and alarming functionality:

1. Increase in the quantity of local station alarms from approximately 40 potential alarms to 2500 potential alarms.
2. Local HMI control of 670 control points, including breaker trip and close, reclose state control, blocking protective trips, resetting lockouts, applying clearance tags, resetting relay targets, and initiating carrier tests. Redundant controls are available at the front of the microprocessor relays in the event the HMI computer is unavailable.
3. Local HMI display of almost 700 metering values. The same metering values can be viewed on the rolling displays on the front of the relays.
4. Increase in the SOE data from approximately 300 events to over 2200 events available for viewing locally on the HMI computer or via an HTML page located on the Internet.

5. Approximately 1750 status, alarm, and metering points available for viewing and trending data via a PI server located in the General Office. These data were not available prior to the integration upgrade.
6. Increase in the number of remote TCC control points from 64 to 278, analog points from 174 to 370, and alarm and status points from 81 to 819.

## COMMUNICATIONS ARCHITECTURE IMPROVES RELIABILITY

The integration communications architecture is in a star configuration where the microprocessor relays and station monitoring devices are connected to ports on the communications processor via a serial communications link. This architecture provides a very reliable communications scheme. The star configuration allows multiple and simultaneous communications to occur between the relays and the communications processor, allowing massive amounts of data to be collected and passed to the HMI by the microprocessor relays. A critical design criterion of the integration architecture was to develop a complete backup control system in the event of both HMI and SCADA failure. This was met by utilizing the local bits control on the front of the microprocessor relays. In addition, complete redundant station alarm, status, and metering data are available via the LEDs and on the rolling display on the front of the relays.



**Figure 10** Communications One-Line Overview

## HUMAN-MACHINE INTERFACE IMPROVES STATION OPERABILITY

The HMI computer provides enhanced station operability and functionality. The HMI provides complete substation operator control, metering, status, and alarming. A tremendous amount of input from station operators, field technicians, and training coordinators was collected during the evolution of their automation program, and the HMI has become a very user-friendly interface for operating the station.



**Figure 11** Primary Operator Interface From HMI



**Figure 12** Duplicate Controls at Front of Relays

## Enhanced Station Controls

The station operator can perform station controls with the click of a mouse, utilizing fast messaging by initiating a control command that passes to the communications processor. The communications processor decodes the message and passes the command to the microprocessor relay. By utilizing the internal logic, including latches and control bits, the operator can trip and close breakers, block protection schemes, reset lockouts, and apply clearance tags. The HMI screens provide a user-friendly interface that significantly reduces potential operator errors. For example, for a circuit breaker to be operated, several screens have to be accessed and the final operate screen asks the operator “Are you sure you want to perform this operation?”

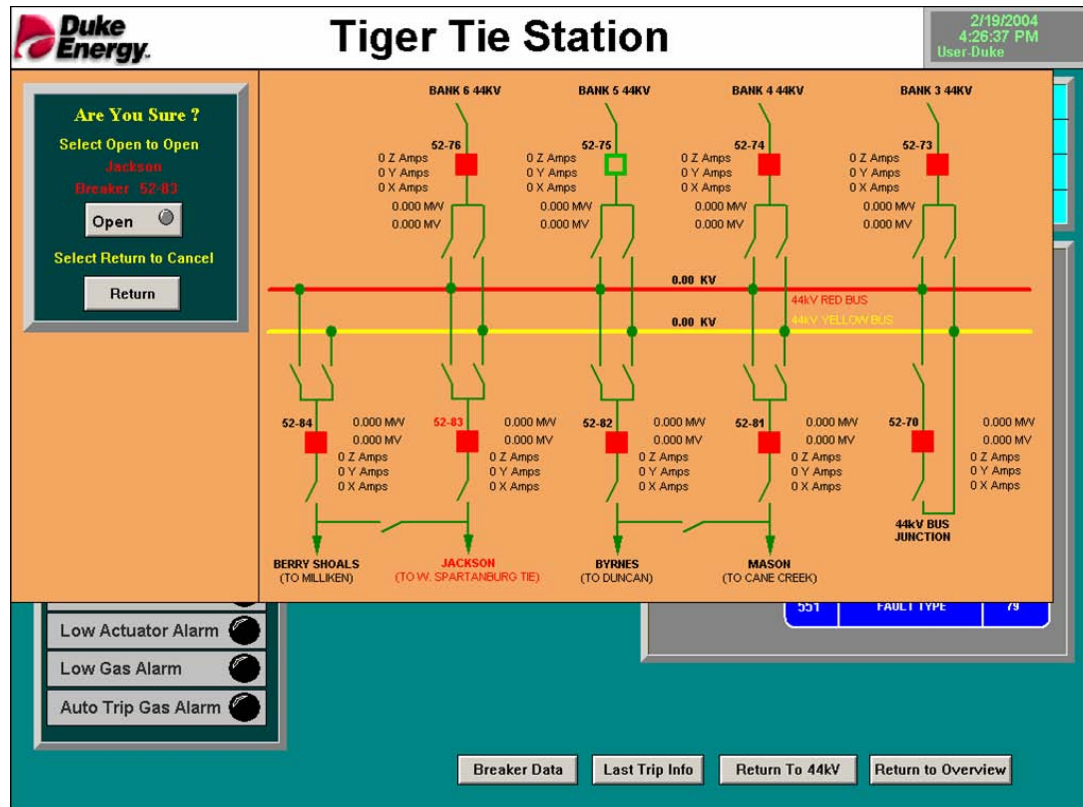


Figure 13 Example of HMI Operator Interface—Circuit Breaker Trip

## Enhanced Real-Time Metering and Status

The HMI displays station one-lines with real-time metering and status data that allow the station operator to quickly determine the status of the station equipment and load flows. Status information available to the operator includes breaker status, circuit reclosing status, and lockout trip status. Status of protective schemes is displayed on the HMI, including underfrequency blocking, breaker failure blocking, fault pressure blocking, and ground overcurrent blocking. Metering data available to the station operator on the HMI include circuit amps, voltage, watts, vars, and frequency. Circuit fault magnitude and location is available on the HMI for the station operator to view and rectify system outages more quickly.



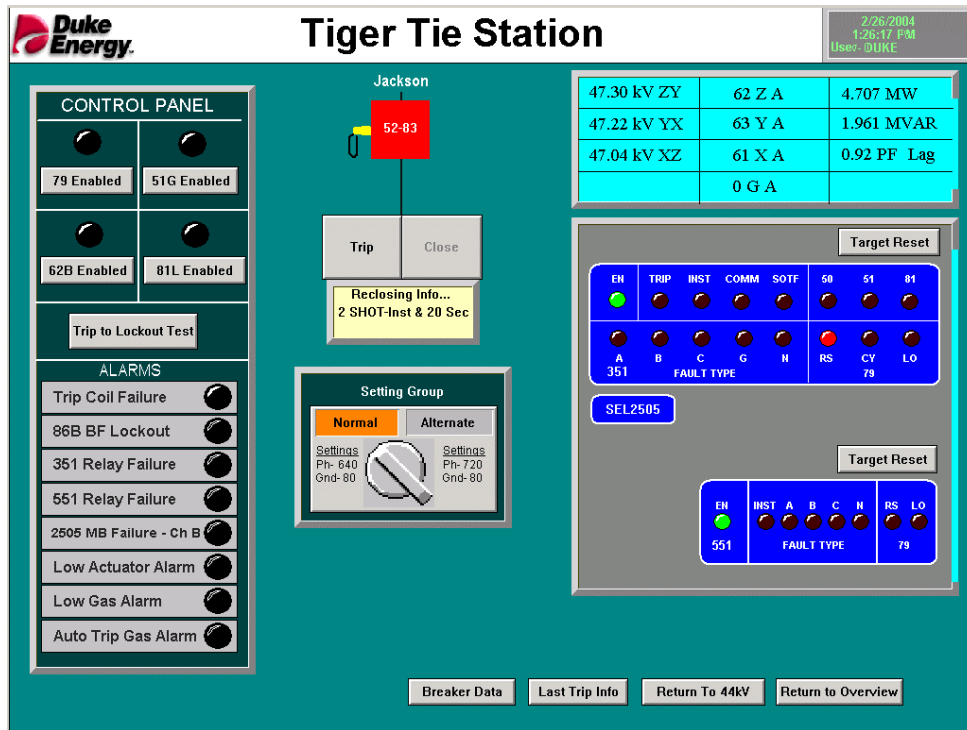


Figure 14 HMI Screen—Typical Circuit Screen—Controls, Alarms, Status Information

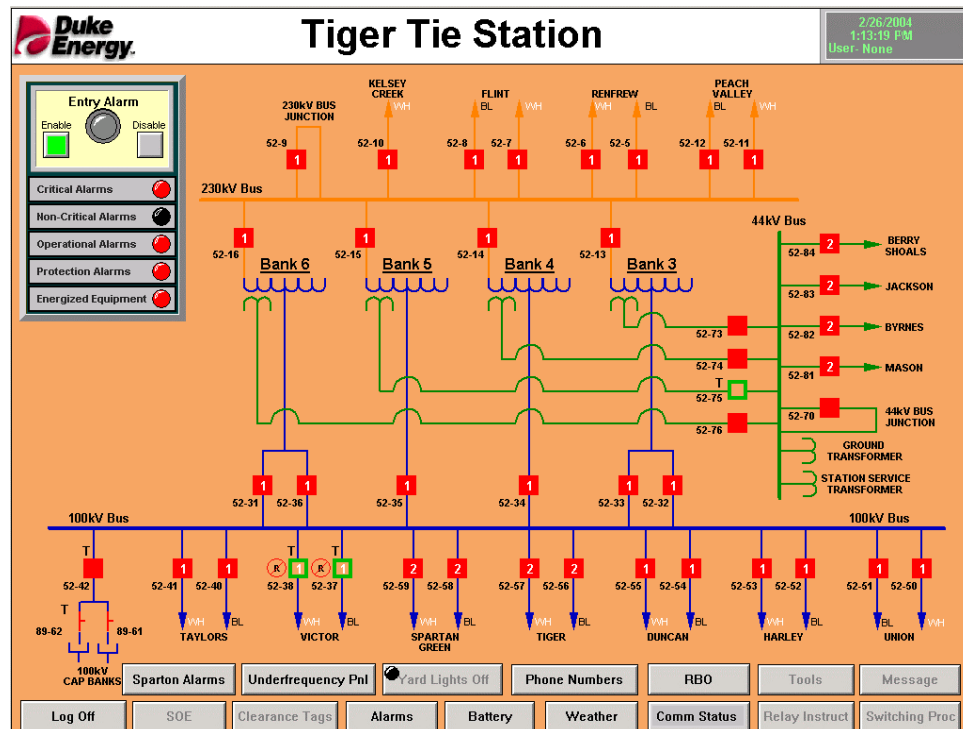


Figure 15 HMI—Station Overview Screen

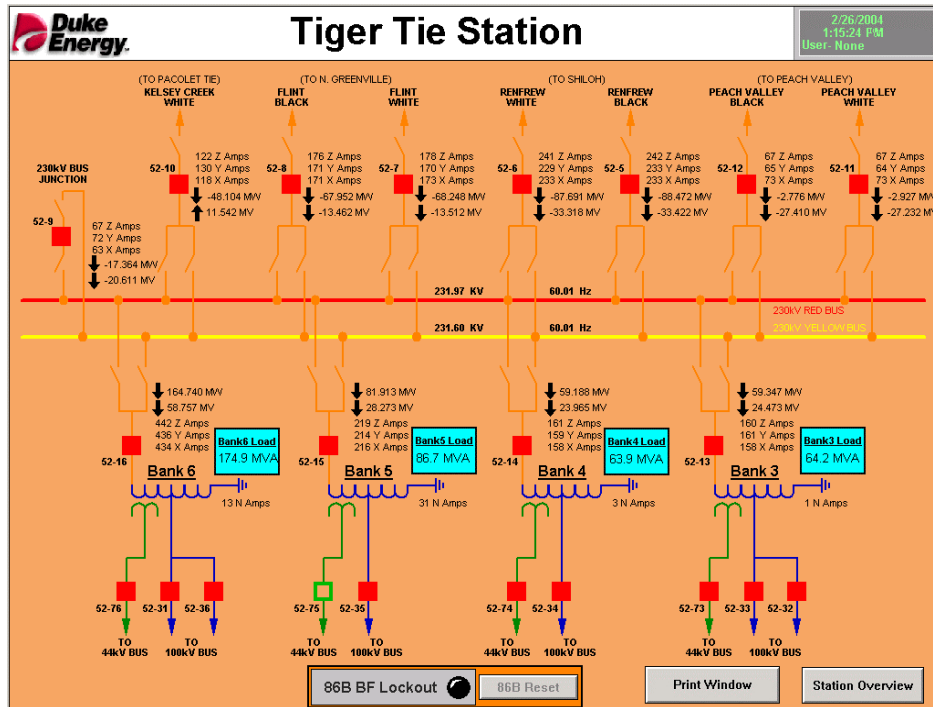


Figure 16 HMI—230 kV One-Line Screen

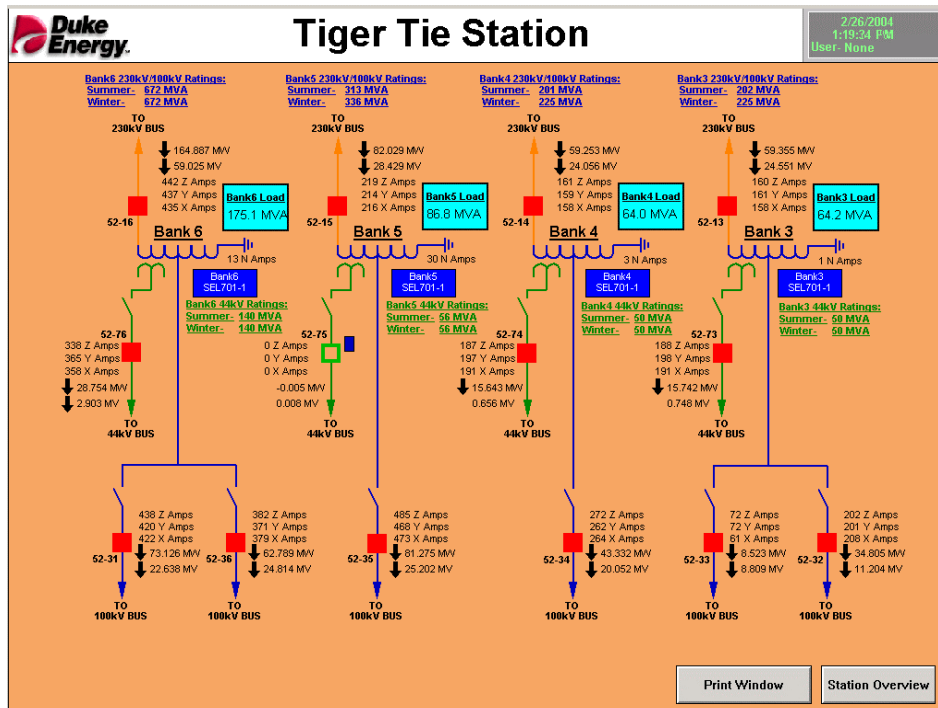


Figure 17 HMI—Autobank One-Line Screen

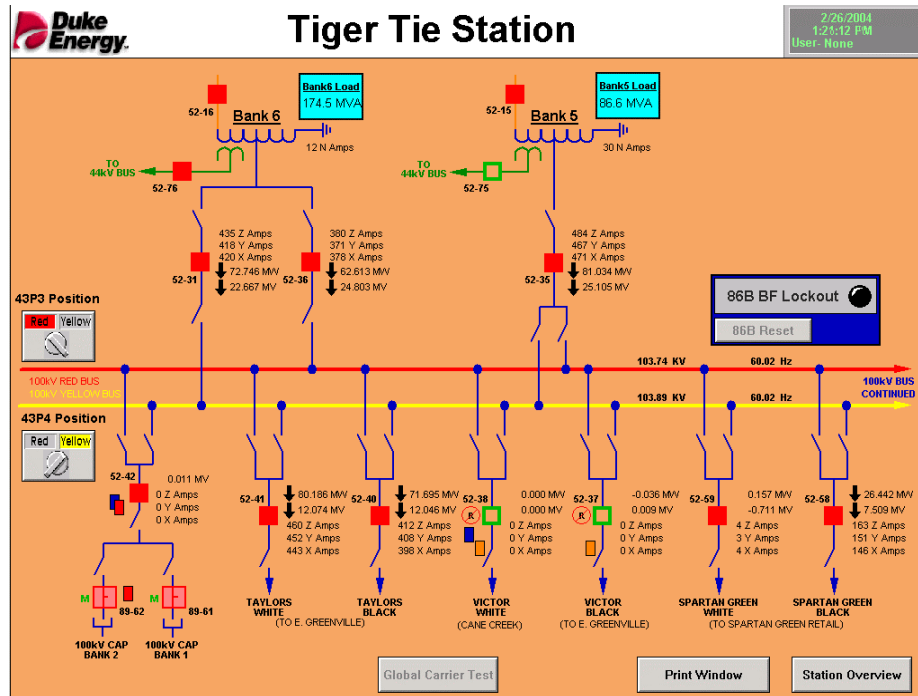


Figure 18 HMI—100 kV One-Line Screen

## Enhanced Station Alarming

The station alarm viewer at the HMI computer provides the station operator with a more detailed summary of the status of the substation equipment by giving the operator the ability to select specific equipment or circuit alarms. The alarm detail and selection ability provides the station operator with a better understanding of any station equipment, relay, or communications issues and allows for a quicker rectification of the problem.

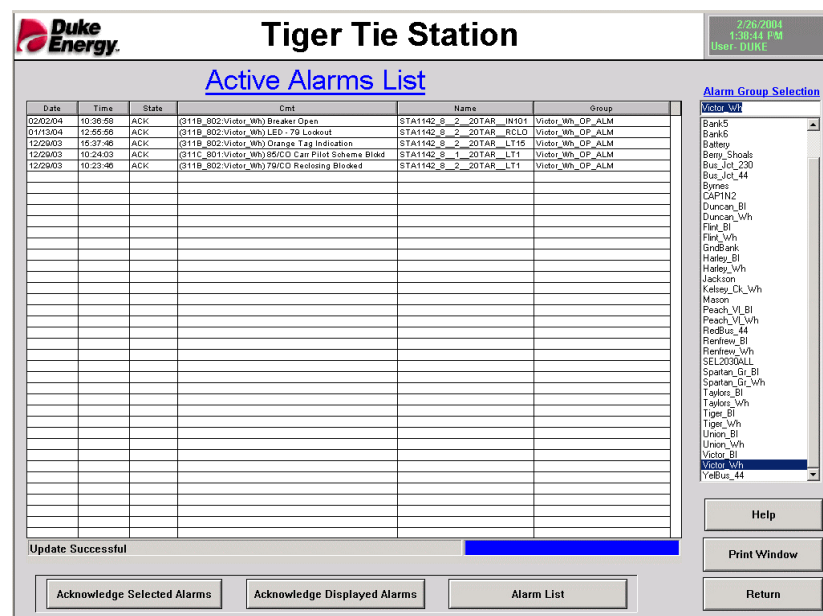


Figure 19 HMI—Alarm Screen (showing active alarms)

## DC System Monitoring

The battery charger provides dc system alarming and metering data to the HMI display via a fiber-optic link to the communications processor. The battery system metering data include battery charge current, battery voltage, service voltage, and battery temperature. The battery system alarms include low battery voltage, high charge rate, high battery voltage, battery symmetry, positive ground, negative ground, and component failure. The readily available information reduces time in troubleshooting battery system problems and reduces maintenance cycles.

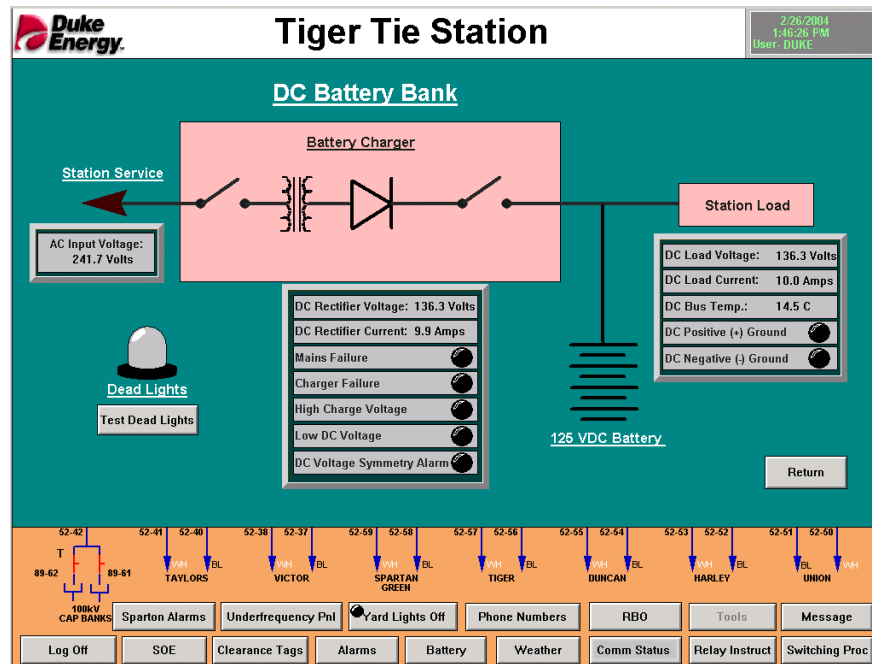


Figure 20 HMI Screen—DC System

## Enhanced Breaker Monitoring

The microprocessor relays provide breaker condition monitoring that includes breaker percent wear and accumulated interrupted amps, which allows the elimination of individual monitoring devices. The breaker condition monitoring utilized in the relays reduces maintenance costs by eliminating periodic maintenance cycles and replacing them with predictive maintenance. Other breaker monitoring data available include breaker operations counter, trip coil monitor, low air monitoring, air compressor run indicator, and SF6 gas alarms.

## Electronic Clearance Tagging

The station operator can apply clearance tags from the HMI computer for circuit breaker or line maintenance or repair work. The clearance tag on the HMI allows the station operator to provide much more detailed information, which improves operational safety concerns and allows better communications between different station operators. The HMI computer has a historical database that keeps a detailed historical log of all clearance tags applied, thus eliminating hard copy filing systems.

Date Applied	Tag Type	
2004/02/19 10:03:51	RED	C
2004/02/19 10:34:41	RED	C
2004/02/10 10:22:40	BLUE	C
2003/12/29 15:37:46	ORANGE	V
2003/12/29 15:37:17	ORANGE	V
2003/09/10 15:22:29	BLUE	B
2003/06/25 12:12:11	BLUE	V

**RED TAG**  
FORM 475408 (R1-00)  
DUKE ENERGY CO. Electric Transmission  
**DEENERGIZED EQUIPMENT**  
**CLEARANCE ISSUED**  
THIS EQUIPMENT SHALL "NOT" BE ENERGIZED UNTIL ALL PERSONAL PROTECTIVE GROUNDS ARE REMOVED AND THIS TAG HAS BEEN PROPERLY REMOVED.  
STATION: Tiger Tie Station  
EQUIPMENT: CAPIN2  
SWITCHES OPENED:  
100KV CAP PCB CAP RACK SIDE DISC RED BUS DISC YELLOW BUS GANG  
NUMBER OF GROUNDS INSTALLED: 0  
CLEARANCE ISSUED TO: MACEMORE  
TAG INSTALLED BY: BVB  
TIME: 10:03:51 AM DATE: February 19, 2004  
AUTHORIZED BY: TCC  
NUMBER OF GROUNDS REMOVED:   
CLEARANCE RELEASED BY:   
TAG REMOVED BY:   
TIME: DATE:   
AUTHORIZED BY:   
Print Cancel Save Add New Remove Edit Egit  
Show Active Tags Show Removed Tags Transmission. 0 7 1:43 PM 2/26/2004

Figure 21 HMI—Clearance Tag Display

## Enhanced Station Monitoring and Control Utilizing the Communications Processor

In addition to performing the data concentration and SCADA functionality, the communications processors perform nonprotective-related control and logic, including emergency lighting control, control house entry alarm, yard lighting control, emergency station service (SS) alarming, and communications-related alarms.

## PROTECTION AND CONTROL IMPROVEMENTS AT TIGER TIE

### Eliminating Power Line Carrier Equipment for the 230 kV Tie Lines

The existing directional comparison blocking (DCB) pilot protection scheme for the 230 kV tie lines utilized Power Line Carrier equipment for relay communications, including analog transmitter/receiver carrier sets, wave traps, CCVTs, and tuning units. These communications components required costly periodic testing and maintenance. Due to the increasing maintenance costs and the fact that aging equipment is prone to more frequent failures, the engineers looked at alternative solutions for modifying the relay-to-relay communications pilot protection scheme at Tiger Tie. A large percentage of the 230 kV and higher voltage transmission lines have fiber-optic ground wire cable (OPGW) installed that is used for linking to the communications network. Due to the availability of a link to the fiber network at Tiger Tie and the 230 kV tie line remote-end substations at Pacolet Tie, Peach Valley Tie, North Greenville Tie, and Shiloh Tie substations, it was decided to utilize the fiber network to provide the relay-to-relay pilot communications medium for the (7) seven 230 kV tie lines. Eliminating the Power Line Carrier communications medium meant that all associated equipment was removed from service.

An intelligent multiplexer was installed at Tiger Tie and at the (4) four remote-end tie substations. Port 3 of the primary distance SEL-421 Relay was configured for MIRRORED BITS<sup>®</sup> communications and was connected to a communications port on the IMUX that provided the link to the fiber network. Port 3 of the SEL-421 Relay at the opposite remote-end substation was configured for MIRRORED BITS communications to provide the communications path between the relays at each end. A POTT scheme utilizing the internal logic of the microprocessor relay provides the primary distance pilot protection.

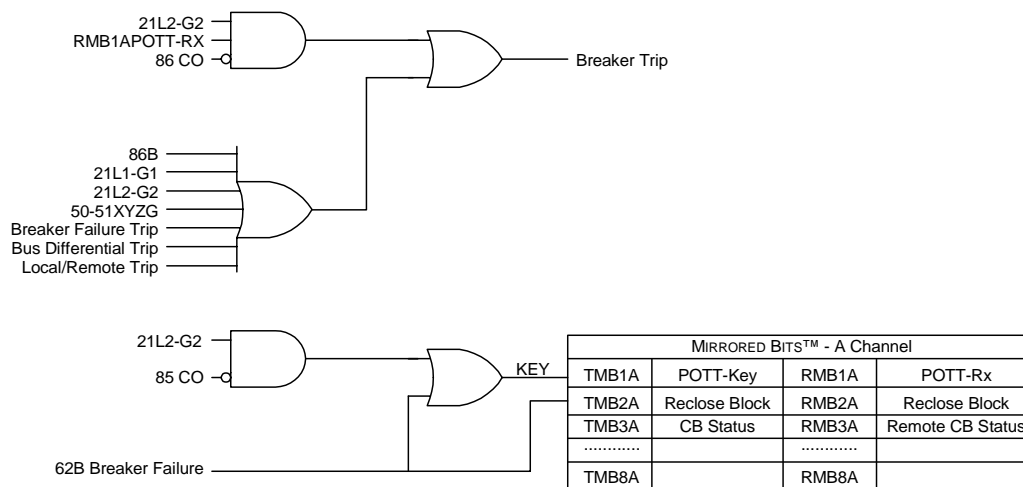


Figure 22 POTT Logic Diagram

### Elimination of the Transformer Fire Protection System Emulsifier Panels

The original design for the autobank transformers at Tiger Tie consisted of a commercial fire protection system panel with a separate 24 Vdc system. The emulsifier fire protection system consisted of the digital control panel, heat sensitive protectowire wrapped around the transformer, and a dense water spray system that engulfs the transformer for cutting off the oxygen in the event of a transformer fire. The water comes from a large water tower located outside the substation. The engineers designed logic in the autobank differential microprocessor relay to

mimic the same functionality as the fire protection system digital control panel. Moving the fire protection controls into the protective relay eliminated expensive fire protection panels from the new relay and control design.

## Incorporating the Automatic Carrier Test in the Microprocessor Relay

Tiger Tie substation has (4) four 100 kV transmission tie lines using Power Line Carrier for its DCB scheme. The traditional design for automatic carrier transmit/receive testing utilizes discrete relays, timers, and PLCs located on the relay panels and a playback module at the remote ends. For the protection and control upgrade at Tiger Tie, the relay engineers incorporated the same transmit/receive testing functionality within the primary distance relay by utilizing its control logic. The test can be initiated at the HMI or from the front of the relay. Utilizing logic in the communications processor, the test is also automatically initiated once a week at a specified time on all four lines simultaneously. This test simulates a real trip condition and tests the integrity of the Power Line Carrier equipment. If the response carrier signal is not received for a specified time period, an alarm is issued to the station HMI and TCC. Incorporating the control within the protective relays realized savings by eliminating unnecessary components and eliminating the need for a service technician to perform a manual weekly test.

## Underfrequency Load Shedding Replacing Separate Relay Panels

Traditional Utility protective design required separate relaying for performing underfrequency load shedding at a substation. At Tiger Tie, the underfrequency load shedding protection and functionality was incorporated into the transmission line primary distance relay by utilizing available protective and logic elements within the relay. The underfrequency protection blocking control is at the station HMI and on the front of the relay. This eliminated unnecessary additional relays and components.

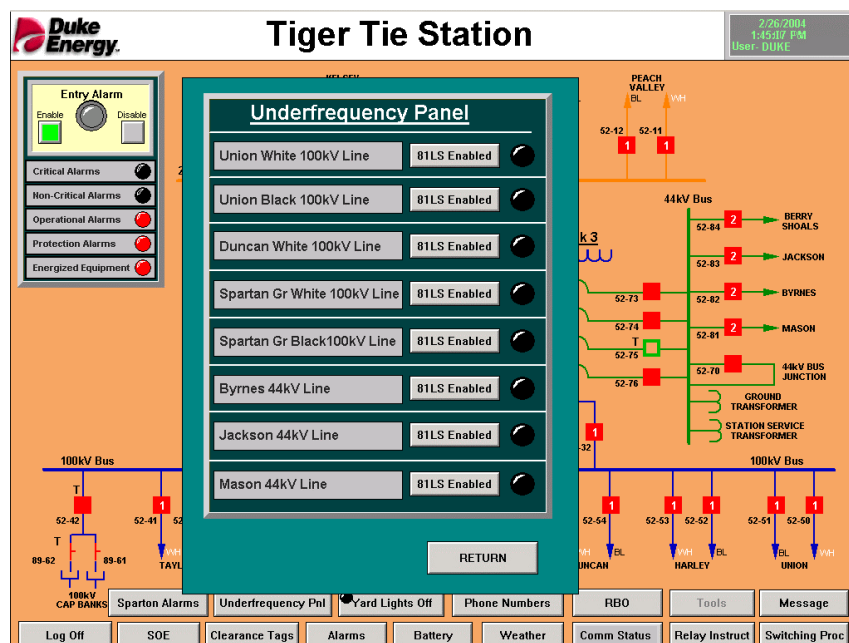


Figure 23 HMI—Underfrequency Control

## Enhanced Transformer Annunciator and Fan Controller

The existing autobank annunciator and automatic fan controls were replaced with a microprocessor relay mounted at the transformer and linked back to the communications processor using a fiber-optic cable. This eliminated control and alarm cabling between the transformer and the control house. The alarming and fan and pump control functionality is achieved by utilizing the internal logic in the relay. The enhanced control includes automatic fan/pump daily cycling, automatic fan/pump control based on bank winding and oil temperatures, and automatic fan/pump tripping for a bank lockout trip. Additional transformer alarms are available, including fan/pump amps, fan/pump failure alarms, fault pressure device alarm, slow gas alarm, liquid level alarm, and RTD failure.

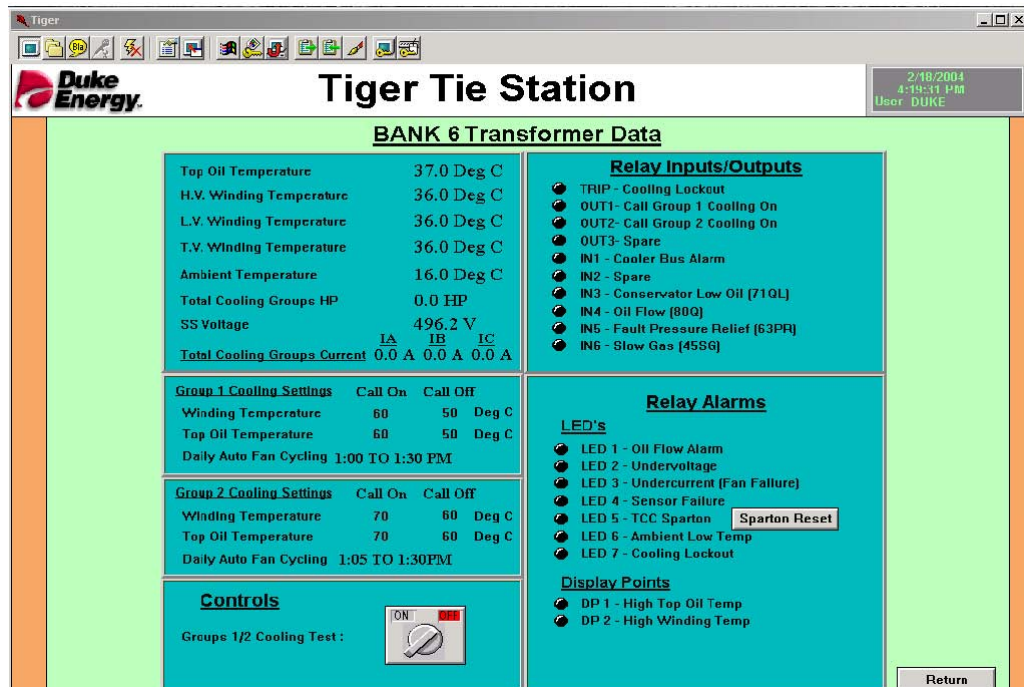


Figure 24 HMI—Autobank Monitoring and Fan Control

## Replacement of PLC Capacitor Control

Utilizing its internal logic capabilities, the microprocessor relay is programmed to perform the capacitor bank automatic control function as well the protection function. The relay logic control provides a more robust automatic capacitor controller, linking the capacitor control and operation to the protective functions.

## Autobank Loss-of-Life Monitoring

By utilizing the thermal elements in the transformer microprocessor relay and monitoring the oil and winding temperatures, alarm points are set to activate for specific conditions when the transformer overheats or is in danger of excessive insulation aging or loss-of-life. Data are captured daily from the transformer relay and passed on to the PI server located in the General Office for continuous monitoring of the autobanks. Tracking of these critical provides key predictive maintenance data that reduce the potential for catastrophic bank failures.



## Elimination of RTU and Enhanced Remote Controls and Alarms

The communications processors used for data collection and controls to the local HMI computer are also utilized for station remote control and alarming via an industry standard DNP3 link back to the TCC. The communications processors linked to the microprocessor relays provide significantly more control capabilities and alarm count to the TCC. The additional alarming and control functionality significantly reduces operational costs by allowing the remote operators to perform specific control functions that were typically performed by an operator dispatched to the station.

## Elimination of Separate Sequence-of-Events Records

The SOE data points in each microprocessor relay are passed to the HMI computer for viewing. The HMI SOE program allows the station operator to view relay elements, including protective elements, logic points, and inputs/outputs. The ability to view much more detailed SOE data allows the relay engineers and operators to quickly troubleshoot system misoperations.

Date	Equipment	Device	Element	Description	State	Operate
2004/02/25 10:29:16.739	Taylors_BI	311B_805	79L0	Reclose Rly in Lockout State	DEASSERTED	
2004/02/25 10:29:16.739	Taylors_BI	311B_805	79RS	Reclose Relay in Reset State	ASSERTED	
2004/02/25 10:29:15.738	Taylors_BI	311B_805	LT1	79 Reclosing	IN-SERVICE	
2004/02/25 10:22:16.817	Taylors_BI	311B_805	LT1	79 Reclosing	BLOCKED	
2004/02/25 10:22:16.817	Taylors_BI	311B_805	79L0	Reclose Rly in Lockout State	ASSERTED	
2004/02/25 10:22:16.817	Taylors_BI	311B_805	79RS	Reclose Relay in Reset State	DEASSERTED	
2004/02/25 08:36:22.606	Taylors_BI	311B_805	79L0	Reclose Rly in Lockout State	DEASSERTED	
2004/02/25 08:36:22.606	Taylors_BI	311B_805	79RS	Reclose Relay in Reset State	ASSERTED	
2004/02/25 08:36:21.606	Taylors_BI	311B_805	LT1	79 Reclosing	IN-SERVICE	
2004/02/25 08:18:04.088	Taylors_BI	311B_805	LT1	79 Reclosing	BLOCKED	
2004/02/25 08:18:04.088	Taylors_BI	311B_805	79L0	Reclose Rly in Lockout State	ASSERTED	
2004/02/25 08:18:04.088	Taylors_BI	311B_805	79RS	Reclose Relay in Reset State	DEASSERTED	
2004/02/24 17:31:03.107	Taylors_BI	311C_804	LT1	85/CO Carrier Pilot Scheme	IN-SERVICE	
2004/02/24 17:30:48.478	Taylors_BI	311C_804	LT1	85/CO Carrier Pilot Scheme	BLOCKED	
2004/02/24 17:29:42.489	Taylors_BI	311B_805	LT2	51G GND Overcurrent	IN-SERVICE	
2004/02/24 17:29:31.394	Taylors_BI	311B_805	LT2	51G GND Overcurrent	BLOCKED	
2004/02/24 17:29:08.491	Taylors_BI	311B_805	79L0	Reclose Rly in Lockout State	DEASSERTED	
2004/02/24 17:29:08.491	Taylors_BI	311B_805	79RS	Reclose Relay in Reset State	ASSERTED	
2004/02/24 17:29:07.491	Taylors_BI	311B_805	LT1	79 Reclosing	IN-SERVICE	
2004/02/24 17:29:59.459	Taylors_BI	311B_805	LT1	79 Reclosing	BLOCKED	
2004/02/24 17:29:59.459	Taylors_BI	311B_805	79L0	Reclose Rly in Lockout State	ASSERTED	
2004/02/24 17:29:59.459	Taylors_BI	311B_805	79RS	Reclose Relay in Reset State	DEASSERTED	
2004/02/23 17:49:41.955	Taylors_BI	311B_805	79L0	Reclose Rly in Lockout State	DEASSERTED	
2004/02/23 17:49:41.955	Taylors_BI	311B_805	79RS	Reclose Relay in Reset State	ASSERTED	
2004/02/23 17:49:40.955	Taylors_BI	311B_805	LT1	79 Reclosing	IN-SERVICE	
2004/02/23 07:09:43.846	Taylors_BI	311B_805	LT1	79 Reclosing	BLOCKED	
2004/02/23 07:09:43.846	Taylors_BI	311B_805	79L0	Reclose Rly in Lockout State	ASSERTED	
2004/02/23 07:09:43.846	Taylors_BI	311B_805	79RS	Reclose Relay in Reset State	DEASSERTED	
2004/02/22 02:00:19.562	Taylors_BI	311C_804	SV11	Carrier Test Receive	DEASSERTED	
2004/02/22 02:00:19.562	Taylors_BI	311C_804	IN103	RFL9785 Carrier Blck Receive	DEASSERTED	
2004/02/22 02:00:15.632	Taylors_BI	311C_804	LT4	Automatic Carrier Test	DEASSERTED	
2004/02/22 02:00:15.628	Taylors_BI	311C_804	SV11	Carrier Test Receive	ASSERTED	

Figure 25 Sequence-of-Events Display

## Replacement of Circuit Breaker Annunciators

SEL-2505 I/O devices were mounted in each circuit breaker and linked via fiber to the microprocessor relay located in the control house. These devices provide a local breaker annunciator and eliminate excessive control wiring between the control house and the circuit breakers.

## IMPLEMENTATION HIGHLIGHTS

During the implementation of the drop-in control house automated solution, specific station work is required to minimize equipment downtime and limit additional installation complexities. From the initial drop-in solution implementations in 2000, the engineers realized that performing the station upgrades while using the existing cabling system was an impossible task. It was evident that a completely new redundant cable system would be required. Since a majority of these cables at the selected stations were due for replacement anyway, the decision made for cable and tray replacement became an easy economical decision. At Tiger Tie, a completely new tray, conduit, and cable system was installed.

During the implementation of a drop-in control house automated solution, it makes sense to address other station or apparatus issues while crews are deployed and equipment is out of service. Even though additional funding is required to make these additional improvements, this approach results in a much more thorough upgrade and limits future substation rework due to obsolescent and legacy equipment that may be due for replacement. Prior to the start of the Tiger project, the engineers identified issues relating to station electrical apparatus and station facilities. A majority of the station apparatus and facility improvements were completed before the control house arrived on-site. By completing these improvements in advance, the field crews can concentrate solely on the protection and control installation and commissioning once the new house arrives. Some of the station improvements could not be completed until circuits could be taken out of service during the commissioning phase.

These are the apparatus and station improvements implemented at Tiger Tie:

1. Installation of a new cable tray and conduit system separate from the existing tray system.
2. Installation of new current, voltage, and control cables separate from the existing cables.
3. Installation of new fiber-optic cable and innerduct for communicating to apparatus IEDs.
4. Complete upgrade of the station service system, including transformers and ac load centers.
5. Complete upgrade of station lighting.
6. Replacement of obsolete and aging 230/100 kV potential devices.
7. Complete replacement of yard differential boxes.
8. Relocation of station perimeter gate and widening of entry gate to accommodate location of new control house.
9. Periodic maintenance and repair of station apparatus, including circuit breakers and autotransformers.



**Figure 26** New Tray and Conduit System Installed at Tiger Tie



**Figure 27** New Control House Piers Poured and Cables Installed Before the Control House Arrives



## Field Testing and Checkout

A thorough acceptance checkout is performed on the pre-wired relaying and control equipment in the drop-in control house before the commissioning phase begins. Depending on the size of the substation, the acceptance testing can be performed off-site or after the control house arrives at the station (at Tiger Tie, due to the size of the station and the amount of detailed testing required, it made sense to perform the testing on-site once the control house arrived). Once the control house arrives, a PLC simulator is set in the house and wired to terminals in the field termination boxes. The PLC simulator is used to duplicate the operation and status of the circuit breakers and circuit switchers.

The Tiger Tie checkout was completed in approximately 2 1/2 months. The checkout included upgrading the microprocessor relays and communications processors with the latest firmware and settings, and complete protective relay and scheme testing. The HMI and relay controls were thoroughly tested, including breaker controls and alarms, reclose blocking, protective element blocking and indication, lockouts status and resets, and clearance tags. The metering data were tested and verified on the HMI, including circuit amps, voltage, watts, vars, frequency, and circuit fault magnitude and fault location values. Also verified were dc system data and breaker monitoring data. The HMI station alarming and SOE applications were also thoroughly tested. In-depth system control and functionality training was given to the station operators during this time.

## Commissioning Phase and Temporary Trips

During the commissioning and cutover phase of the project, it was essential to keep a majority of the station protection intact through the entire commissioning period. This task must be thoroughly thought out and planned. Due to the complexity of the protection and control schemes at Tiger Tie, keeping both primary and backup protection in service at all times was difficult. The engineers and field specialists devised a detailed plan for wiring temporary trips and current differential circuits. Temporary bus differential tripping for the 230 kV, 100 kV, and 44 kV buses was accomplished by utilizing fiber-optic-linked SEL-2505 I/O devices mounted at the old existing control house and the new drop-in control house. The commissioning phase of the Tiger Tie automation project of cutting over each circuit to the new control house took approximately 8 months.



**Figure 28** Field Technician During Commissioning

## KEYS TO THE SUCCESS OF THE TIGER TIE PROJECT

The integration upgrade of a major system transmission substation, Tiger Tie, was a major accomplishment for the Utility in 2003. A single measurement of the success of the project was the fact that there were no misoperations and safety-related incidents during the implementation and commissioning of the new relaying and control equipment. There were several keys to the success of the Tiger Tie project, which has become a “showcase” example for the substation automation program at this Utility.

1. Support from management team

The full support from members of the Utility management team played a key role in getting the proper resources, funding, and materials to complete a successful project.

2. Dedicated engineering team

This Utility had a dedicated engineering team that concentrated solely on the engineering, design, and implementation of the automation projects, where each member had a specific role and responsibility relating to the project. The engineering complexities of substation automation make a focused core group critical for the seamless work flow and the success of the project.

3. Proven and standardized design standards

This Utility has implemented 15 integration upgrades since 1999 and has established proven relay and control standards that significantly accelerated the engineering and design process for the Tiger Tie project with minimal potential errors.

4. Long-term vendor relationships

This Utility has established long-term relationships with vendors for engineering and design services, and control house and panel construction. These long-term relationships have allowed these vendors to become familiar with their standards, which have reduced vendors’ engineering, design, and construction costs as well as their bottom-line costs. These relationships also allow for faster service in equipment deliveries and modifications.

5. Standardized station relay and control components

This Utility has standardized on highly reliable relay and control products. By standardizing on station components, the costs associated with engineering, design, station operability, and training are significantly reduced.

6. Field technicians and system operators’ acceptance of automation solution

The field technicians and system operators played an integral part in the development of the automation solution from the beginning of the program in 1999. The engineering team realized that it was very critical to the success of the automation program to involve the field personnel in the design and development of the control and relaying schemes. Getting a tremendous amount of field personnel input and getting their “buy-in” made the implementation phase of the Tiger Tie project a major success.

7. Dedicated field personnel team

One of the major hurdles of implementing the transmission substation upgrades is keeping a consistent, knowledgeable, dedicated team of field personnel—including relay and apparatus specialists and technicians, substation technicians, and system operators—for the entire testing and commissioning phase of the project. Getting regional managerial support to keep

the dedicated team focused on the project played a key role in making the installation phase of Tiger Tie successful.

8. Detailed work plan and commissioning procedures

Assigned members of the field commissioning team wrote detailed procedures for each circuit cutover. Before each planned outage, meetings were held to review the switching procedures and the detailed work plans to ensure that all team members understood the work being completed. The detailed meetings and procedures were essential in making Tiger Tie error free and without safety instances.

9. Pre-commissioning plan

A detailed commissioning plan was developed before the start of the testing and commissioning phase of the Tiger project. Because of the importance of Tiger Tie substation to the support and stability of the electrical grid, some circuits were not available during extreme loading periods, specifically during the summer months. The field installation team and operating coordinators developed a schedule based on these concerns.

10. Incentive

A payout incentive was given to all project team members. The payout was based on the project team meeting safety goals, having zero human error instances, and meeting project deadlines and project budget goals.

## CONCLUSION

The drop-in control house strategy utilizing integrated microprocessor relays and communications processors provides an excellent solution for the problem of obsolescence of substation electrical protection and control assets. With the completion of the sixteenth automated transmission substation, this Utility has realized significant improvements in system reliability and operability, as well as significant cost savings in capital, operational, and maintenance expenditures. By increasing the system functionality at the TCC, the additional alarming and control data allow the remote operators to perform control functions that were previously unavailable and could only be performed by operators dispatched to the station. Maintenance cycles are now performed on a predictive cycle versus preventative cycles, by trending and tracking the tremendous amount of station data points now available at the General Office via the PI server. A simplified operator interface and improved station alarming and monitoring data allow station operators to operate these stations much more efficiently, especially during emergency situations when rectifying system outages. Significant improvements in substation safety issues as well as a reduction in potential human errors have been realized with the integrated solution at these stations. Relay and control design standards using fewer components have been established, significantly reducing engineering and design time. With the development of solid, more simplistic relay and control standards, the outsourcing of the engineering, design, and implementation of a drop-in control house automated solution is easily achieved.

## BIOGRAPHY

**Douglas M. Arcure** received his BSET from Fairmont State College, Fairmont, WV in 1985. Doug was the Lead Engineer for the implementation and commissioning of the Tiger Tie Substation Automation Project and has played a key role in the design, engineering, and development of the substation automation initiative at Duke Power. Doug has worked as a System Protection Engineer with Duke Energy and Florida Power & Light. Doug has worked as an Electrical Engineer with General Electric and Asea Brown Boveri performing project management, engineering, and commissioning duties on industrial automation and control and power system upgrade projects. Doug has also worked as an Electrical Supervising Engineer at the world's largest desalination plant at Saline Water Conversion Corporation (SWCC) in Jubail, Saudi Arabia for 2 1/2 years. Doug holds professional engineering licenses in the states of North Carolina and Pennsylvania.

**Chris K. Clippinger** received his BSEE from the University of North Carolina at Charlotte in 1988 and is a registered professional engineer in North and South Carolina. He started work at Duke Power and worked in several departments during his career, including Nuclear Engineering Services Department, Fossil/Hydro Engineering, and the Electric Transmission Division of Duke. Chris's responsibilities while at Duke included the development of protective relay standards, scoping of new installations and system modifications, and served as the solution development leader on the integration team charged with the revitalization of Duke's transmission substations. Chris is currently employed with Schweitzer Engineering Laboratories and is the Supervising Engineer over the Systems and Services Charlotte Division. He is responsible for overseeing the engineering services being performed by this department. Chris is an active member of the IEEE and PES subcommittee.